Decentralised Energy Systems in Aotearoa: securing our future

Report 2: Infrastructure of the future: a new asset management paradigm

SEANZ
Sustainable Energy Association New Zealand

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This report is part of a series by SEANZ examining the key barriers and enablers to decentralised energy solutions. The series provides recommendations to support uptake, reduce consumer costs, strengthen system resilience and economic certainty, and enable consumer interaction with the energy market.

Executive Summary

Electricity demand is expected to nearly double by 2050, bringing with it significant infrastructure investment requirements. Non-wire solutions have the potential to accommodate this new demand on the grid the most cost effectively by flattening demand peaks and balancing intermittency. This management both supports affordability and is critical for system security as the electricity network becomes more complex with more connected customer energy resources (CER) and a greater reliance on more intermittent renewable generation. The value of demand-side flexibility is recognised by New Zealand's latest Government Policy Statement for Electricity.[1]

While such solutions will have significant benefits across New Zealand's electricity infrastructure, the focus of this report is on distribution infrastructure, where the impact of forecast new demand is likely to be concentrated.

Non-wire solutions enable distribution networks to avoid some network capacity upgrades, and for this reason, the report will refer to them as Non-Wire *Alternatives* (NWAs). Whilst the role of aggregated and managed demand is significantly under-leveraged in New Zealand, we also acknowledge that not every network upgrade can be displaced by the procurement of flexibility services. However, we believe that in many instances they can be. This report is concerned with such instances.

We will explain how connected capacity - such as a customer owned battery - managed as aggregated demand (procured by EDBs) can avoid or defer capital expenditure which would have been passed on to customers. The meaningful procurement and integration of flexibility services requires the right network capabilities and standards. Such capabilities constitute the foundation of our conceptualisation of DSO (Distribution System Operation) functions.

Electricity Distribution Business (EDB) investment into NWA as a matter of standard asset management also requires the right incentives.

The forgone investment which would be achieved through NWA by way of distribution deferral is typically capital expenditure (capex) - spotlighting the incentives for EDBs to make, or avoid, capex. Because these incentives are derived from economic regulation, the report will scrutinise this framework - setting out the current state of play, and changes that could be made to better align this framework with a new asset management paradigm.

There is a 'chicken and an egg' relationship between EDB procurement of flexibility solutions

1. "Statement of Government Policy to the Electricity Authority under section 17 of the Electricity Industry Act". October 2024. Hon Simeon Brown as Minister for Energy. 2010:https://www.beehive.govt.nz/sites/default/files/2024-10/Government%20Policy%20Statement%20on%20Electricity%20-%20October%202024.pdf

and the existence of flexibility markets. Whilst there is a lot of activity centred around the trial of flexibility solutions, and discussion around the shape of the new markets they will inhabit, New Zealand is lagging behind the rest of the world in the emergence of flexibility markets and integration of customer energy resources (CER).

This current inertia traverses both the investment incentives at the heart of New Zealand's economic regulation (the price quality framework) and market regulation (the definition of flexibility markets and the scope of EDBs' DSO role within that). Policy and regulatory steps to overcome this inertia therefore need to bring these two regulatory domains together to enable a new technological and market paradigm to emerge, in service of our infrastructure transformation.

Unlike the silicon valley model of disruption, this transformation (being based on physical infrastructure) is less about finding a new disruptive technology and more about integrating the ones that already exist at scale. This directs focus to the market and regulatory framework as the true locus of disruption for our energy transformation given that it is this framework which incentivises or discourages the integration of technologies.

Specifically, we recommend:

Overarching regulatory principles

1. Outcomes rather than process

2. Fair reward for avoided cost

3. Long time horizon in assessing customer outcomes

Recommendations for economic regulation

- Implement a totex (total expenditure) approach in the price-quality regime
- Extend the regulatory period to fifteen years and introduce stronger uncertainty mechanisms to allow changes in allowable revenue within this period
- Allow EDBs to earn a margin on payments for flexibility services and implement a Shared Savings Mechanism (SSM) in which savings that are incurred by way of NWA are shared between EDBs and their customers
- Mandate the consideration of NWAs in investment and planning decisions
- Implement an Output Delivery Incentive (ODI) for DSO capabilities and flexibility procurement in the economic regulatory framework

Institutional recommendation

- Strengthen the alignment between economic and market regulatory functions including consideration of institutional consolidation.

Recommendations for market regulation

- Define DSO roles and requirements
- Establish a single national flexibility trading platform

To develop these recommendations we undertook close analysis of New Zealand's price-quality framework as well as a landscape scan of equivalent regulation in international jurisdictions. This included the United Kingdom (UK); Denmark; Ireland; Ontario, Canada; Australia; Singapore and California. Learnings from this review have been integrated into our recommendations.

Infrastructure of the future: a new asset management paradigm

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Demand is forecast to grow significantly

Under various scenarios from multiple analysts, New Zealand's electricity requirements will increase significantly over the next 25 years. Key drivers for this are:

- Electrification of transport
- Displacement of fossil fuels in residential and commercial applications
- New commercial loads from data centres
- General population growth

MBIE's 2024 Electricity Demand and Generation Scenarios report forecasts the following:

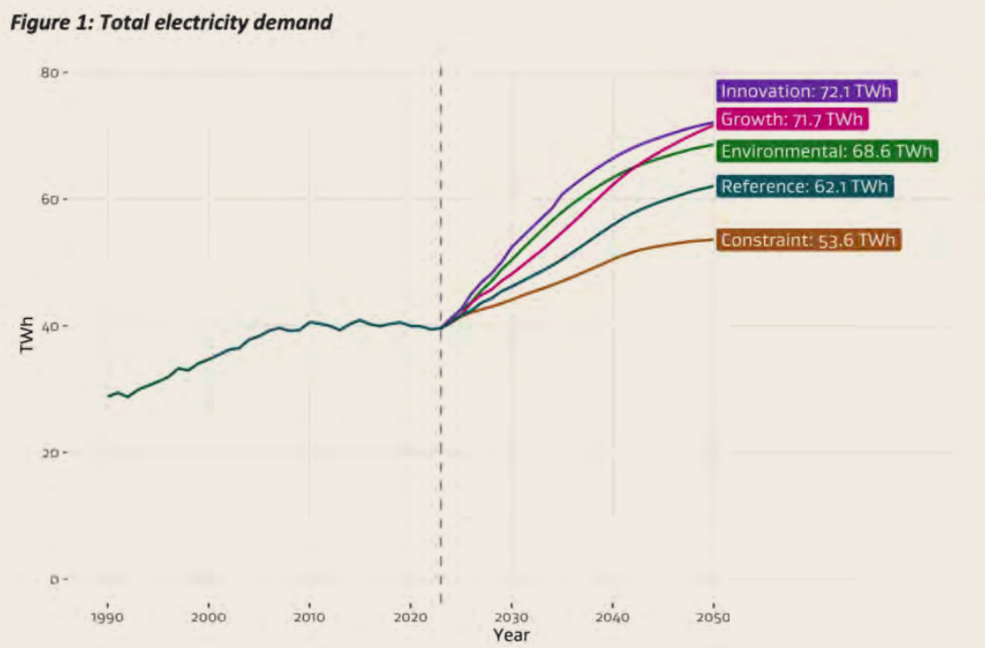


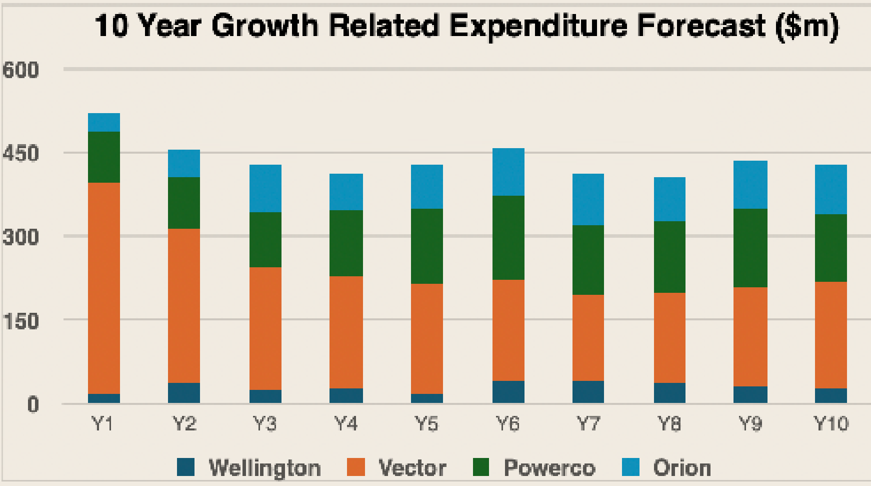
Image 1: Electricity Demand and Generation Scenarios, MBIE 2024

As stated by the Electricity Networks Association (ENA), electricity needs to increase from its current contribution of serving 25% of our total energy needs to around 60% by 2050.[2] This new demand represents a massive increase in investment in new network infrastructure.

2. "Briefing to the Incoming Minister for Energy". Electricity Networks Association (ENA). February 2025. https://www.ena.org.nz/our-work/document/1538. pg 4

Forecast demand growth has resulted in significant forecast investment

EDBs have made significant allowances in their 10-year asset management plans for demand growth. For the 4 largest EDB's, forecast expenditure for system growth and security of supply is forecast to be $4.35b.



Total 10-year growth forecast $4.35b

Image 2: Summary of analysis from the latest Asset Management Plans

The Auditor General's report "Electricity Distribution businesses: Observations from the 2023/24 audits", published in June this year, reported on the increase in forecast capital expenditure (capex) of consumer trust or council owned EDBs for the period 2024/25 - 2033/34 compared with actual capex for the period 2021/22 - 2023/24.

Figure 5: Average change in forecast capital expenditure for 2024/25 to 2033/34 compared to actual capital expenditure for 2021/22 to 2023/24

Average change in forecast capital expenditure	Number of public energy companies
Decrease from the average	3
Increase between 0% and 25%	2
Increase between 25% and 50%	8
Increase between 50% and 75%	5
Increase greater than 75%	1

Image 3: Increase in forecast capex across public energy companies, Auditor General report of public energy companies, 2025. Source: Our analysis of public energy company forecasts, as collated by the Commerce Commission.

The impact of this investment on energy affordability is not a foregone conclusion

Despite these levels of investment, electrification need not be unaffordable.

This is firstly because increases in household energy bills (driven initially by higher consumption) will be offset by a reduction in the consumption of fossil fuels (for example, exchanging petrol for a customer's car with far cheaper electricity). Independent analysis undertaken by Sapere and commissioned by the ENA found that households using purely electric appliances combined with an Electric Vehicle will soon begin to comparatively reduce their total energy spend, with annual savings reaching ~$2000 per annum by 2040.[4]

Secondly, savings accrued through the electricity supply chain by more optimal investments and asset management - including leveraging flexibility markets and customer technologies - will also accrue to more customer savings overall. That is, effectively integrating new (to the supply chain) technologies has the potential to do the same - if not more - for less.

In sum, while a steep increase in our reliance on electricity is certain, the magnitude of cost increases that will flow from greater infrastructure investment is not a pre-determined or fixed reality, but rather, will depend significantly on the nature of those investments.

As above, the greatest number of these 19 publicly owned (and audited) EDBs have forecast an increase in capex of 25-75%.[3] This is significant, with the cost of this investment recovered through prices.

Indeed, the latest default price-pathway (DPP4) - which sets out the allowable revenue and quality standards for regulated EDBs (which will be explained further) - resulted in an average annual increase of 24% of distribution revenue for year one - an increase to consumers' power bills of $25 per month in some cases.

3. https://www.oag.parliament.nz/2025/energy-companies/docs/energy-companies.pdf;

4. "Briefing to the Incoming Minister for Energy". Electricity Networks Association (ENA). February 2025. https://www.ena.org.nz/our-work/document/1538. pg 11

The definition and role of non-wire solutions

What is a non-wire solution?

Non-wire solutions can reduce the impact of new demand on existing infrastructure – delaying or avoiding investments (which push up prices to all consumers). These solutions include hardware (such as batteries and distributed generation) and software (such as digital platforms for optimised network planning, operation and the procurement of flexible resources).

This report distinguishes network owned and operated non-wire solutions from solutions which are owned or operated by customers or other third parties in competitive markets.

Solar and battery solutions which fall into this competitive category (and which are 'behind the meter') are referred to as Customer Energy Resources (CER). Network owned and operated batteries and solar generation will be referred to as Distributed Energy Resources (DER). We note and support the impending Energy and Electricity Security Bill, which is set to expand the ability of an EDB to invest in connected generation.

Similarly, digital platforms which are owned and operated by third (non-network) parties (such as the UK's Piclo Flex or Electron) are distinguished from a network's own digital assets (such as a SCADA system or grid virtualisation tool). As we will discuss further, we recommend a single national flexibility market platform for New Zealand.

For clarity, in this report, tools which enable an EDB to plan for, procure and integrate aggregated resources are referred to as Distribution System Operation (DSO) capabilities. We distinguish such capabilities from the functions of aggregating customer demand for the provision of flexibility as an ancillary service.

How do non-wire solutions work to save money?

Aggregated resources such as discretionary home and industrial loads, EV charging, on-premise battery storage and solar inverters can be managed to help meet growing demand needs more cost effectively than increasing network capacity. That's because the strategic deployment of these resources can be used to 'flatten' peak demand, avoiding or deferring the need to increase network capacity to meet higher peaks. This can also help balance the system as more CER are integrated on the demand side - and as more renewable generation increases intermittency on the supply side.

While the circumstances and costs triggering traditional network investments will vary significantly, the following examples show some "typical" scenarios in comparing traditional network investments with the deployment of a residential customer battery.

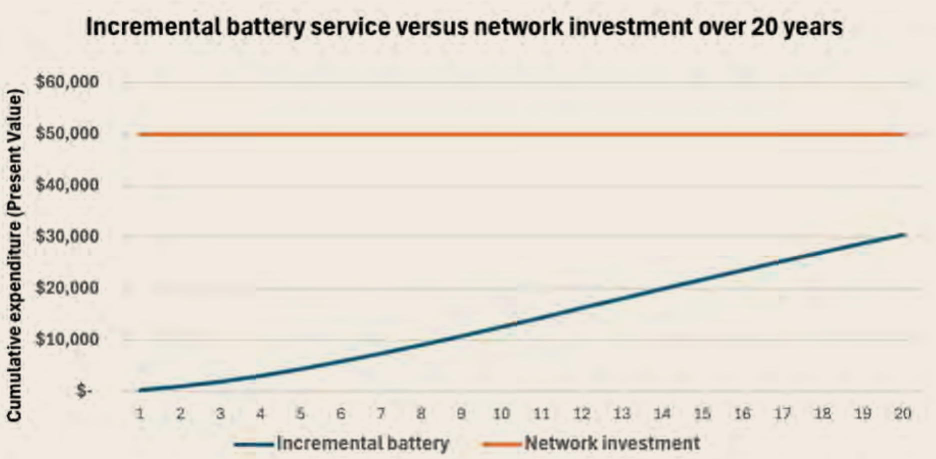
Based on upper end forecast demand projections which have electricity demand doubling over the next 25 years, an annual increase of 4% is assumed. Distributed home battery storage is used as the basis for the service. (10kWh battery capable of reducing the peak demand by 4kW).

The customer compensation level for the battery storage has been set at a minimum to cover the cost of an additional 5kWh battery module. Prices of battery modules are allowed to decrease by 4% per annum, and the monthly fee for batteries each year have been allowed to decrease on this basis.

LV Transformer

Current load	200 kVa
Growth rate	4%
Annual increase	8 kVa
Peak demand reduction per battery	4 kVa
Number of batteries needed per year	2
Monthly payment to customer	$15
Forecast drop in battery pricing pa	4%
Interest rate	6%

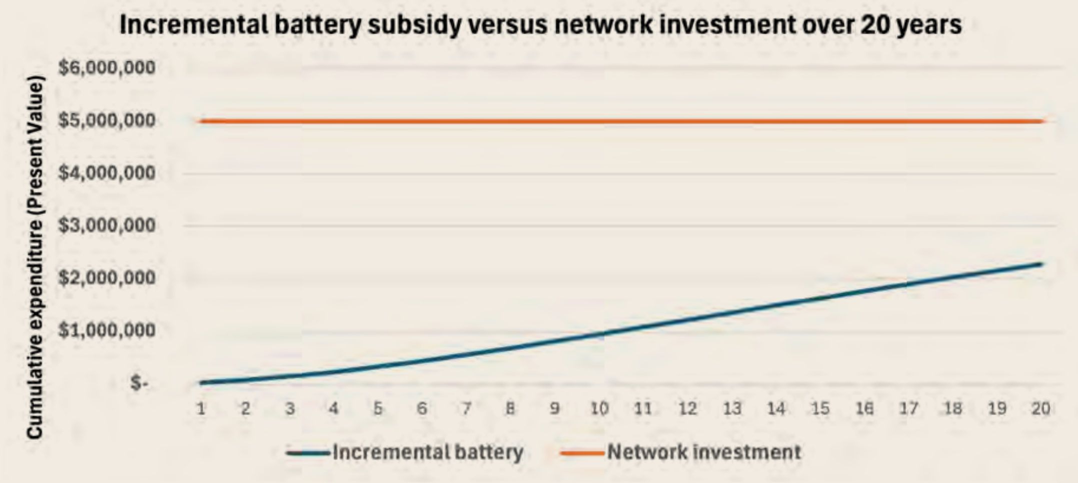
PV of customer receipts (Y1) $2,239.65 (over 15 year battery life)



11kV Feeder

Current load	7500 kVa
Growth rate	4%
Annual increase	300 kVa
Peak demand reduction per battery	4 kVa
Number of batteries needed per year	75
Monthly payment to customer	$30
Forecast drop in battery pricing pa	4%
Interest rate	6%

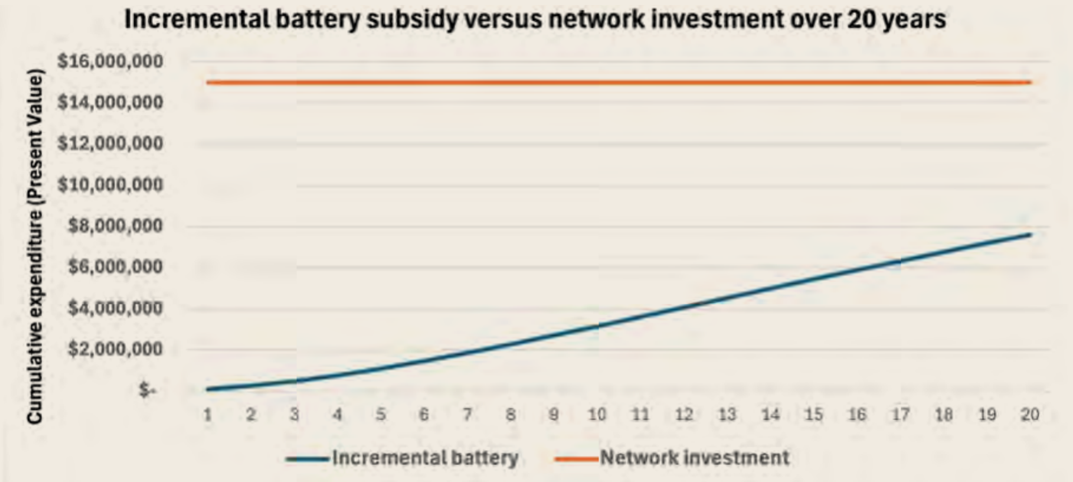
PV of customer receipts (Y1) $4,479.30 (over 15 year battery life)



Zone Substation

Current load	30000 kVa
Growth rate	4%
Annual increase	1200 kVa
Peak demand reduction per battery	4 kVa
Number of batteries needed per year	300
Monthly payment to customer	$25
Forecast drop in battery pricing pa	4%
Interest rate	6%

PV of customer receipts $3,732.75 (over 15 year battery life)



In some cases, batteries installed at premises would avoid infrastructure investments simultaneously across LV, 11kV and Zone substations.

A network could leverage CER (by way of procuring this flexible resource from demand aggregators) as part of its asset management. This would incur consumer savings through avoided investment in traditional infrastructure, as demonstrated by the above examples.

Some EDBs are leading the way in building DSO capabilities - although these efforts are piecemeal and the consistent integration of flexible resource is under developed

As highlighted by Saul Griffith in the book *Electrify: An Optimists Playbook for our Clean Energy Future*, transforming energy infrastructure - which is primarily hardware - is not the same as the silicon valley model of disruption. As much as smart technologies - such as demand aggregation and management - have a key role to play in our infrastructure transformation (being a key feature of this report) our energy infrastructure is still primarily physical, and our energy transformation is less about a new single breakthrough innovation and more about the integration of existing technologies at scale.

To transform our infrastructure we do not need a new trial, pilot, or one off project - we need to align our market framework, the business models within it, and the regulatory framework which governs it - to a new asset management paradigm.

A new asset management paradigm requires a new regulatory paradigm

Current state of play

The price quality framework

Currently the asset management practices of EDBs and the price and quality of their services are regulated by the Commerce Commission within the economic regulatory framework set out in Part 4 of the Commerce Act. This price-quality framework sets the allowable revenue of an EDB expressed through the Maximum Allowable Revenue (MAR) in the first year of the regulatory period (starting prices) followed by the rate at which maximum allowed prices can increase year on year, within the five year regulatory period. Under this 'CPI-X' formula, prices are restricted from increasing each year by more than the rate of inflation, less a certain number of percentage points. Recognising the relationship between price (and the expenditure that this reflects) and network quality, reliability is also regulated by this regime in by the frequency and duration of unplanned outages.

The Commerce Commission uses forecast capital expenditure (capex) and operational expenditure (opex) set out by EDBs in their asset management plans (AMPs) to estimate the efficient cost of service and to set the MAR. Within this regime, allowed capex is added to the Regulated Asset Base (RAB) where it can be depreciated and where it earns a rate of return - which is determined by the Weighted Average Cost of Capital (WACC).

Operational expenditure (opex) however, is treated as a pass through and is recovered in the year that it is incurred. Whilst this faster recovery accelerates cash-flow, it also foregoes the rate of regulated return. This creates a systemic incentive for EDBs to favour capex over opex. Because capex includes system growth and traditional asset replacement and renewal whilst opex includes system operations and network support (including any increase in the use of flexibility services) the price quality regime as it stands disincentivises NWAs directly. This disincentive is compounded by the fact that the increased deployment of such flexibility services is likely to reduce the need for further capacity upgrades - reducing the expenditure which can be capitalised further.

Furthermore, as flexibility markets and EDB DSO capabilities are more established, flexibility is more likely to be opex rather than capex - transitioning to a flexibility as a service (FAAS)™ model. This shift from investment in IT capex to opex is already taking place through the adoption in cloud based services[5]

> **There is an uncoordinated nexus between the price quality framework, EDB asset management approaches, and flexibility as a service (FAAS). This is stymying the emergence of flexibility markets**

5. Prepared for the Commerce Commission by Innovative Assets Engineering (IEAngg) "NZ EDB 2023 AMP Review" pg80

Existing regulatory incentives for EDB investment in NWA

To encourage investment in NWAs where the 'resulting efficiency gain/ output of that project is not one that will yield it a financial benefit',[6] the price-quality regime provides an Innovation and Non-Traditional Solutions Allowance (INTSA). Whilst well intended, the INTSA raises the question of why such investments would be uneconomic for an EDB in the first place (particularly when the system efficiency and knock-on value to consumers is clear).

The answer is: the price quality regime overall is not designed to reward these investments. In this context the INTSA is unlikely to have the impact of tilting investment towards NWA to the extent that is desirable for customers.

Furthermore, the design of the INTSA - which is offered as funding for a one-off project - misunderstands the assignment of our energy transformation. Our energy transformation does not turn on finding new breakthrough technologies - rather it relies on the integration of existing solutions at scale.

The existing regime makes another attempt at incentivising efficient expenditure through the Incremental Rolling Incentive Scheme (IRIS) which provides an incentive for an EDB to underspend relative to forecast expenditure by allowing an EDB to keep the difference. Whilst the implementation of a policy decision made in 2023 has evened the treatment of capex and opex within this scheme, this minor bonus for efficiency overall is far from evening the treatment of capex and opex under the current price-quality regime.

6. The Commerce Commission. "Draft EDB Innovation and non-traditional solutions allowance Guidance". 8 May 2025. https://comcom.govt.nz/__data/assets/pdf_file/0026/366128/Commerce-Commission-Draft-Innovation-and-Non-Traditional-Solutions-Allowance-INTSA-guidance-8-May-2025.pdf

Key insights

The price quality regime is fundamentally misaligned with EDB investment in NWA

The price-quality regime provides oppositional incentives to the new asset management paradigm, favouring traditional capex investments through the regulatory return whilst providing a tokenistic allowance for innovation.

Whilst the IRIS may provide a minor incentive for avoided capex (which could be achieved through distribution deferral by way of non-wire alternatives) it is designed to reward a network for money not spent - it is not directly concerned with the decision to invest in one type of asset vs another. And yet this critical choice - made constantly as part of a network's ongoing asset management practice - is the difference between locking in high cost infrastructure upgrades for future generations vs stimulating the emerging market for smart energy technologies, strengthening New Zealand's innovation economy and driving the most affordable energy transformation possible.

The key question at the heart of encouraging investment in NWA is not "how much is an EDB spending?" it is "what are they spending it on?". That is, the challenge is not just about encouraging less expenditure (as is rewarded by the IRIS for both capex and opex) - but it is about exchanging forecast capex for greater opex. An alternative approach to the treatment of capex and opex is a totex approach. We describe this further in our recommendations.

The five yearly DPP period does not appear to support investment in NWA

As mentioned, opex is recovered in the year it is incurred, as opposed to decades as is the case for capex. Therefore, exchanging capex for opex may concentrate an uplift in prices in the short term by increasing expenditure which is recovered faster. However, as demonstrated by our analysis, this could result in lower capital recovery in future years and overall.

Just as an EDB has duties to its shareholders (in many cases these shareholders are customer or council owned trusts), the Commerce Commission has duties to the public. We note the Commission's focus on ensuring that the impact of DPP4 on pricing was moderated by spreading the uplift in recovery across future years within the DPP period[7]. We support the concern for customer affordability that this reflects. However, as we have set out: greater investment in NWAs can

7. "Joint RCP4-DPP4 Final decisions for Transpower and electricity distribution price-path resets". the Commerce Commission. https://www.youtube.com/watch?si=-_1WhbKG3SUt3u5U&embeds_referring_euri=https%3A%2F%2Fcomcom.govt.nz%2F&source_ve_path=MTM5MTE3LDM2ODQyLDEzOTExNywyODY2NCwxNjQ1MDY&v=sYMW9ELhLjk&feature=youtu.be;

significantly reduce investment in more expensive traditional network infrastructure. Therefore, greater opex may offset avoidable capex. Whilst this may increase EDB expenditure which is recovered today (and possibly prices in the short term), it would also result in a significant net saving for customers when the decades-long life of the traditional network asset which has been avoided, is taken into consideration.

We appreciate that a bias towards present outcomes (as opposed to future) is much broader and deeper than the price-quality regime. However, we question whether the five-yearly regulatory view of the distribution sector's investment is appropriate given the life of the sector's assets can be ten times this. Whilst not all felt today, the cost of an avoidable capital upgrade runs well into the future.

Addressing climate change requires us to prioritise future outcomes as at least equal to present outcomes, and our infrastructure investment requires a long-term approach. If we can leverage our energy transformation to lock-in future savings (rather than cost), increase resilience, and stimulate new flexibility markets to grow our innovation economy, why shouldn't we? We note that research undertaken by the New Zealand Institute of Economic Research (NZIER) has found that the tech sector contributes more to the New Zealand economy than either the dairy or tourism sector. We see the facilitation of flexibility markets as supportive of both the Infrastructure and Innovation pillars of the Government's Going for Growth agenda to unlock New Zealand's potential[8].

As highlighted by Innovative Assets Engineering (IEEngg) in its 2023 review of EDB AMPs undertaken for the Commerce Commission, non-exempt EDBs (which are subject to price-quality regulation) tend to forecast larger capex increases than EDBs which are exempt from this regulation. The authors speculated that the current five yearly DPP period may incentivise non-exempt EDBs to overforecast capex simply because expenditure can only be approved by the Commerce Commission every five years (noting the significant burden of seeking a re-opener) as compared to exempt EDBs whose capex is approved annually by shareholders[9].

Whilst this may seem to contradict the point we make above (seemingly supporting the case for a shorter DPP period) what both points indicate is that the status quo of a rigid five yearly DPP period is not supporting long-term efficiency.

The Revenue = Incentives + Innovation + Outputs (RIIO) regime in the United Kingdom provides an alternative approach with more year on year

8. "Going for Growth: unlocking New Zealand's potential". MBIE. 12.02.2025. https://www.mbie.govt.nz/about/news/going-for-growth-unlocking-new-zealands-potential

9. Prepared for the Commerce Commission by Innovative Assets Engineering (IEAngg) "NZ EDB 2023 AMP Review".

flexibility, building off a consistent revenue base. We address the length of the DPP period - and scope for year on year adjustments - further in our recommendations.

To sum up: Our view on the price quality regime and NWA

Overall the price-quality framework we have today has emerged incrementally in reaction to crises from the late 1990s to now[10]. It was designed to replicate the pressures of a competitive market in order to optimise the expression of business models in a steady-state environment. These business models centred on investing in long life infrastructure and passively recovering this investment over decades – plus the regulated rate of return. As stated by the ENA in their briefing to incoming ministers: "the prevailing regulatory regimes have suited this steady state operating environment"[11]. We agree. However, the imperative to electrify affordably must now usher in new business models and asset management approaches.

What the new asset management paradigm needs

We should not hope for a new transformative technology and nor do we need to. The technology we need exists today – what we need now is the right framework for it to be scaled. We believe that a single national flexibility trading platform is an example of a technology platform that can be deployed at scale to enable a new asset management paradigm – which is supported, rather than challenged, by CER.

Though these CER solutions will increase complexity, if aggregated, the more customer technologies that are integrated to the network, the more stable it will be, and the more potential it will offer to offset greater generation intermittency as we rely more on renewable generation.[12]

10. "Chronology of New Zealand Electricity Reform". Energy Markets Policy - Energy and Resources Branch , Ministry of Business Innovation and Employment.August 2015. https://www.mbie.govt.nz/assets/2ba6419674/chronology-of-nz-electricity-reform.pdf;

11. "Briefing to the Incoming Minister for Energy". Electricity Networks Association (ENA). February 2025. https://www.ena.org.nz/our-work/document/1538.

12. Griffith, Saul. "Electrify: An Optimists Playbook for our Clean Energy Future".

Recommendations

As stated in Report One in this series "Electricity Distribution Pricing – Issues and Solutions", pricing has a key role to play in tilting customer incentives in favour of a smart energy transformation that works for them. There is a parallel need to address EDB incentives and ask whether they inhibit or enable a new asset management paradigm. In sum, driving the integration of CER and emergence of flexibility markets isn't just about ensuring that the right customer incentives are being conveyed, but that the right EDB incentives are also in play.

> "Electricity distribution businesses have, in the past, expressed concern about the substantial, complex, and multiple disclosure requirements. We have seen the effects of this complexity through our work (see Part 2). Our auditors also continue to raise these concerns".
>
> *- Office of the Auditor General, "Electricity Distribution Businesses: Observations from the 2023/24 audits"*

Principles for regulation:

We recommend that these principles act as a north star in guiding the regulation of EDBs.

Outcomes rather than process

There is no lack of regulation across the distribution sector - particularly for non-exempt EDBs. However we question whether this architecture is currently regulating the right things, or in the right way. For example, the disclosure obligations which form part of the price quality regime are onerous, with the Office of the Auditor General concluding:

And yet the connection between such disclosure obligations and EDB asset management approaches and decisions is not a given.

If regulation is just about reporting requirements (as opposed to incentives) then it won't deliver the right outcomes. Whilst we support the need for consistent methodologies for assessing NWA against traditional network infrastructure (per our recommendation below), overall there is a need to focus on outcomes rather than process in the things that are regulated.

Fair reward for avoided cost

Incentivising distribution deferral is about rewarding the right kind of investments, and fairly valuing avoided cost. The existing regime - where expensive network upgrades result in higher revenue - is clearly not aligned with this principle.

And yet the alternative presents a fundamental challenge: how to gain revenue from money not spent. Per the recommendations below, we recommend a totex approach in the price-quality regime to help neutralise the current bias towards capex. But we believe that the challenge of rewarding avoided cost goes beyond our price-quality framework, and touches on incentives at the heart of our commodity based electricity supply chain. We will address this challenge further in subsequent reports.

Long time horizon in assessing customer outcomes

Critical infrastructure is a long-term, intergenerational investment which supersedes electoral cycles and regulatory periods. We must consider the impact of our infrastructure investment, not just on consumers in the next five years – but in future generations. We note and support calls from Business New Zealand for a long-term approach to infrastructure development, and the focus of some sector commentators on asset management - and not just shiny new headline grabbing projects.[13] As a country that ranks high in infrastructure spending but low in efficiency and asset management, we must pursue a new asset management paradigm.

Recommendations for economic regulation:

Implement a totex approach

Rather than submitting forecast capex and opex to the Commerce Commission, an EDB would submit its total expenditure and a capitalisation rate would be applied across this expenditure. As is the case in the United Kingdom, this rate would determine the portion of an EDB's expenditure that can be capitalized (earning the rate of regulated return expressed as WACC + depreciation recovery) rather than immediately

13. "New Zealand's Infrastructure Challenge: from planning to delivery". Sarah Sinclear for the NZ Herald, 5/08/2025. https://www.nzherald.co.nz/business/business-reports/infrastructure-report/nzs-infrastructure-challenge-from-planning-to-delivery-sarah-sinclair/GBNAUDAXQNFWXLC4EMQIZNPT6E/

‘capitalizing’ the share of an EDB’s expenditure that is actually capex. The UK regulator, the Office of Gas and Electricity Markets (Ofgem), takes into account precedent, the substantive nature of the spending, as well as cashflow needs and financeability in determining the totex capitalization rate. As such the actual rate of capital expenditure is not irrelevant to this capitalization rate - which is different for each Distribution Network Operator (DNO), and typically hovers at around 60%. Whilst such a totex approach is a step towards capex-opex neutrality, incentives to capitalise more expenditure (such as to spread cost recovery over a longer time horizon) may still persist. For this reason we also recommend a longer regulatory period to encourage a longer term view of efficient cost recovery.

Extend the regulatory period to fifteen years and introduce stronger uncertainty mechanisms to allow changes in allowable revenue within this time more easily than the current re-opener process

The time horizon of the five year DPP period is a small share of the total life of traditional network assets, and whilst more opex (as a proxy for digital NWAs) may have a shorter recovery period, they may also avoid future cost. Conversely, every capex upgrade made in the next five years locks in cost for consumers for decades to come. Whilst the totex capitalisation rate would go some way in neutralising the bias towards capex for EDBs, this would not dispel the incentive that regulators may have to defer cost (and price) uplift to future years by way of a higher capitalisation rate. Whilst Part 4 provides for a price quality regime that promotes the long-term benefit of consumers, the framework with its five year horizon does not align with this goal. Whilst a fifteen year regulatory period is unprecedented in the price-quality regimes we surveyed, it would achieve alignment with the number of emissions budgets which have to be in place at any one time under New Zealand’s Climate Change Response (Zero Carbon) Amendment Act 2019. Under this legislation, there has to be three five-yearly budgets in place at any one time - with mechanisms to change them if necessary.

The greater mechanisms for change would help make the longer regulatory cycle sustainable - but may also in itself reduce the apparent incentive for non-exempt EDBs to over forecast capex, as compared to exempt EDBs. We note that the UK re-calculates allowable revenue every year, building off a ‘base allowable revenue’. This base allowable revenue is set for each of the five years based on the EDBs’ expected costs across the regulatory period, at the beginning of the regulatory period (unlike the MAR for year one and CPI-X for subsequent years in New Zealand). However, through the Annual Iteration Process (AIP), output incentives, indexation, totex reconciliation and uncertainty mechanisms (which allow for adjustments to demand, inflation, volume drivers) are recalculated each year, changing the annual allowed revenue from the base. We recommend greater flexibility in adjusting allowable revenue for EDBs within the context of a longer regulatory period.

Allow EDBs to earn a margin on payments for flexibility services and implement a Shared Savings Mechanism (SSM) in which savings that are incurred by way of NWA are shared between the EDB and customers

In order to help offset the lost capital return from investing in flexibility services as opposed to capacity upgrades, we recommend that EDBs are allowed to earn a margin on payments for flexibility services. In Ontario, Canada, EDBs can earn up to 25% for contracting third party aggregated demand providers through a Margin on Payment (MOP). In addition to this the SSM allows an EDB to keep a portion of net savings achieved through distribution deferral whilst the remainder of the savings benefits customers.

Mandate the consideration of NWAs in investment and planning decisions

This would be achieved through: implementation of a common methodology for the assessment of NWA vs network reinforcement; public reporting on procurement processes and outcomes; and, mandated interaction with flexibility markets including a requirement to publish requirements on platforms, and to provide a reasonable time period for responses to these RFPs.

There is strong precedent for this recommendation across the jurisdictions surveyed:

- The UK's RIIO-ED2 framework includes a 'flexibility first' principle requiring DNOs to consider NWAs before proposing traditional network reinforcement.
- To operationalise this principle, DNOs are required to:
  - follow a Common Evaluation Methodology (CEM) when assessing whether to use flexibility or network build;
  - publish their use of this methodology; and,
  - report publicly on procurement processes and outcomes.
- The Australian Energy Regulator (AER) implements a Regulatory Investment Test for Distribution (RIT-D) which EDBs must use to assess proposed network investments against NWAs.
- The European Union's (EU) Clean Energy Package 4 (CEP4) includes provisions that require system operators to procure flexibility and ancillary services through transparent, non-discriminatory market processes.

Implement an Output Delivery Incentive (ODI) for DSO capabilities and flexibility procurement

An Output Delivery Incentive (ODI) would offer an incentive for the delivery of certain outputs, further to an ex post review of EDB activities undertaken by the Commerce Commission. The UK's RIIO-ED2 offers such incentives for the delivery of DNO DSO strategies and plans, with stakeholder feedback and a panel review informing Ofgem's evaluation of such delivery. We support a similar approach in New Zealand and believe that building DSO capabilities should be both required and rewarded. We also believe that the ODI mechanism is consistent with the principle of outcome regulation.

Institutional recommendation

Strengthen the alignment between economic and market regulatory functions including consideration of institutional consolidation

Incentives to invest in non-wire alternatives foundationally stem from the Commerce Commission's economic regulation and the price-quality framework. However the existence of a market from which to procure such solutions - and the role of an EDB in this market - quickly goes to the regulatory purview of the Electricity Authority. Just as Report One touched on the regulatory domain of both the EA and the Commerce Commission, incentivising NWAs requires strong coordination between economic and market regulatory frameworks. We note that across jurisdictions surveyed economic and market regulatory functions were institutionally united around the purpose of regulating energy participants in some cases (for e.g., the UK's Ofgem and Ireland's CRU).

Market regulatory recommendations

Define DSO roles and requirements

There is a varying degree of activity across the sector to define and build DSO capabilities. Whilst we support this leading work we also observe a lack of clarity and consensus which is likely to be inhibiting the emergence of flexibility markets in New Zealand. We recommend that DSO roles for EDBs are defined and capabilities required.

In the UK, DNOs must perform DSO requirements across three main areas:

- planning
- network operation
- market facilitation

This DSO role does not include owning and managing behind the meter assets or CER - but rather is centred on procuring flexibility from other third party aggregators, who manage this connected capacity on behalf of customers. The core role of a DNO in flexibility markets is market facilitation and stimulation, through procurement and procurement protocols. We support this conceptualisation of a DSO role.

Just as there needs to be a consistent definition of DSO functions there needs to be a consistent standard - and consistent and competitive protocols - on how these functions interact with a national flexibility market. In sum, EDBs need to be engaging with flexibility markets - and there needs to be equal access terms and transparency around procurement processes to ensure that this engagement drives competition and optimal customer outcomes.

Establish a single national flexibility trading platform where EDBs procure flexibility from third party aggregators

Whilst we note that some jurisdictions have multiple flexibility trading platforms, given the scale of New Zealand's market we recommend a single national flexibility market in New Zealand. Whilst our distribution infrastructure is physically dispersed, creating a single nationalising flexibility trading platform is a way of achieving national consolidation as we step into a new digital paradigm.

An example of this is Denmark's Fast Local Energy Control for Heat (FLECH) which is a flexibility clearing house / market framework which enables DSOs and independent aggregators to interact.

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